GUIDE TO TOTAL RESOURCE COST ANALYSIS

DRAFT

THE ONTARIO ENERGY BOARD

July 6, 2005

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Overview

The Guide to Total Resource Cost Analysis (the Guide) has been prepared to assist local distribution companies (LDCs) in meeting the filing requirements for 2005 conservation and demand management (CDM) approval and for making applications for incremental CDM funding in 2006 distribution rates.

In its Decision of December 10, 2004, the Board approved applications by certain LDCs to invest in CDM, conditional on, among other things, the applicants filing quarterly and annual reports on their CDM initiatives.[1] The annual report is to include a cost benefit analysis. This Guide outlines the required analysis and techniques for LDCs to perform the cost benefit analysis.

Similarly, in the 2006 Electricity Distribution Rate Handbook Report, the Board stated that LDCs who plan on seeking incremental funding for CDM in 2006 rates must file a cost benefit analysis in advance of Board approval.[2] This Guide is to be used for the purpose of preparing the cost benefit analysis.

The Guide consists of the minimum expectations of the Board. LDCs are free to use other testing techniques and incorporate other data where appropriate. Where a LDC uses other techniques and data, the LDC must provide evidence to justify the use of alternative techniques or data.

The Guide consists of two elements:

1. An explanatory document for undertaking TRC cost effectiveness analysis, including supporting information, specific direction on key issues, and the mathematical formulae and recommendations related to data requirements and collection techniques; and,

2. A detailed Assumptions and Measures List that provides all requisite TRC input data for a selection of over 100 measures. This list covers a range of typical CDM activities/technologies in residential, commercial and industrial applications. Furthermore:
   - all data is provided on a per unit basis and includes electricity savings, cost, equipment life and free rider estimates, where appropriate;
   - all the information is provided in comparison to a reference case and classified by the decision or installation type – new, retrofit, or replacement.

In combination these two elements provide users with the required information to undertake a TRC analysis.

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[1] RP-2004-0203
[2] RP-2004-0188

The Guide is organized as follows:

Section 1 provides a background on CDM and TRC analysis including the formulae used and a discussion of costs and benefits.[3]

Section 2 focuses on a number of factors and adjustments that affect the TRC test. These include discount rates, free riders, equipment life and persistence.

Section 3 examines issues related to tracking, reporting and evaluating CDM programs.

Section 4 builds on the issues identified in Section 3 and provides examples of how to perform a TRC test screening analysis at the technology, program and portfolio level.

Section 5 consists of the Assumptions and Measures List which is the savings data and required assumptions for most residential, commercial and industrial measures.

[3] A comprehensive history/overview of conservation in Ontario's electricity and gas sectors is available in Appendices A and B of the October 3, 2003 "Board Staff Discussion Paper on Demand Side Management and Demand Response in the Ontario Energy Sectors."

1.0 The Total Resource Cost Model

Conservation and Demand Management programs consist of a set of activities that a LDC undertakes in an attempt to alter the configuration or magnitude of a customer's load.

These activities can encompass a broad set of technologies, measures, market interventions and promotional efforts all aimed at lowering or shifting the customer's demand or energy use.

CDM initiatives can be evaluated on the basis of a cost effectiveness test known as the Total Resource Cost (TRC) test. The TRC test is defined as a test that *"measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participant's and the LDC's costs"*[4]

The TRC test measures the benefits and costs of CDM efforts from a societal perspective. Under the TRC test, benefits are driven by the avoided resource costs. Costs in the TRC test are the costs of any CDM equipment and the program support costs associated with delivering that equipment to the marketplace.

Benefits	Costs
Avoided electrical supply costs	Equipment costs
Other avoided resource costs	LDC program costs

1.1 TRC Calculation

Evaluating the cost effectiveness of CDM is done in stages at many different levels, including technology or measure, program, and then portfolio. The TRC tests can be performed at each level.

At the most detailed level, a TRC test will be performed to evaluate the cost effectiveness of a measure or technology. Once a technology has proven to be cost effective, a program may be designed using that technology. Once the program costs have been assessed, the TRC test will be performed again to evaluate the cost effectiveness of the program. Finally, several programs are bundled together, further indirect costs are included and the TRC test is carried out once again to evaluate the cost effectiveness of the portfolio. This three layered structure; technology or measure, program, and portfolio is key to performing TRC analyses. Figure 1.1 illustrates the "bottom-up" screening process used to develop a CDM portfolio.

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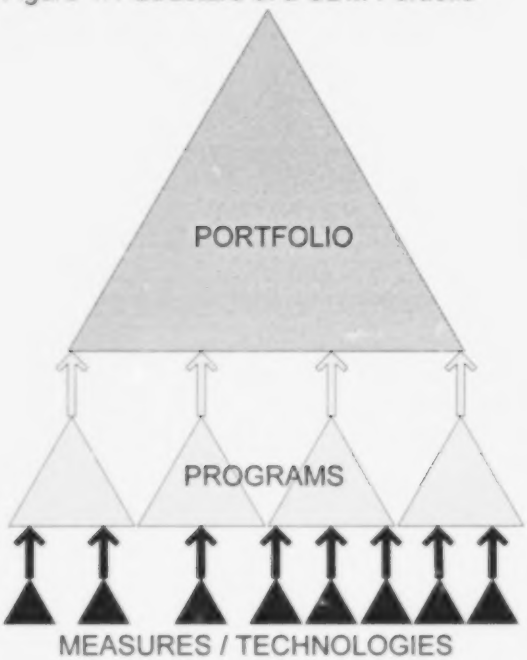
[4]California Public Utilities Commission. (1987) Standard Practice Manual: Economic Analysis of Demand-Side Management Programs

Figure 1.1 Structure of a CDM Portfolio



Data and Assumption Requirements

Indirect costs including overhead, administration, monitoring and evaluation and portfolio auditing

Program direct costs, expected participation, free–ridership rates, attribution levels, persistence factors

Technology/equipment cost, equipments life, savings estimates

The results of the TRC test should be expressed as a net present value (NPV). As a NPV assessment, the TRC test sums the streams of benefits and costs over the lifetime of the equipment/technology and uses a discount rate to express these streams as a single "current year" value.[5] Thus, the NPV_{TRC} is the net discounted value of the benefits and costs over a specified period of time (usually dictated by the equipment life of the CDM technology).

The TRC test is a measure of the change in the total resource costs to society, excluding externalities, due to the CDM program. If the NPV_{TRC} is positive, indicating that benefits exceed costs, the program is considered cost effective from a societal perspective.

1.1.1 Formula for Performing TRC Test

The TRC test examines streams of benefits and costs and uses discounting principles to express these future values as a single number. The benefits stem from the avoided resource costs, typically electricity. The costs are the cost of the equipment and the LDC program costs. Subtracting the costs from the

[5] Discounting is a standard accounting principle which converts future monetary values into current values.

benefits provides the net benefits. For a program to be considered cost effective, the net benefits must be greater than zero.

The NPV_{TRC} formula is as follows:

Figure 1.2: Net Present Value$_{TRC}$ Formula

$$NPV_{TRC} = B_{TRC} - C_{TRC}$$

where;

$$B_{TRC} = \sum_{t=1}^{N} \frac{UAC_t}{(1+d)^{t-1}}$$

$$C_{TRC} = \sum_{t=1}^{N} \frac{UC_t + PC_t}{(1+d)^{t-1}}$$

and,
B_{trc} = the benefits of the program
C_{trc} = the costs of the program
UAC_t = LDC avoided costs in year t
UC_t = LDC program costs in year t
PC_t = Participant cost in year t
N = Number of years for the analysis, (i.e: the equipment life of the CDM technology)
d = Discount rate as approved by the OEB[6]

1.2 Benefits: Avoided Costs

The TRC assesses CDM costs and benefits from a societal perspective. The benefits are defined as "avoided costs". This represents the benefit to society of not having to provide an extra unit of supply – typically expressed as kW and/or kWh. For electricity, supply costs include generation, transmission and distribution including losses.

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[6] Consistent with the Electricity Distribution Rate Handbook and the Distribution System Code, for the purpose of calculating the net present value, LDCs must use a discount rate equal to the incremental after-tax cost of capital, based on the prospective capital mix, debt and preference share cost rates, and the latest approved rate of return on common equity.

Certain CDM programs will have other benefits including other energy sources and water savings. While these savings are not the primary target of the program, the TRC test will accommodate the assessment of savings of other resources including natural gas, heating fuel oil, propane or water. In these cases, the benefits accrue from the avoided costs associated with these resources. LDCs wishing to assess resource savings stemming from other energy forms or water will need to use avoided cost estimates for those resources in the same manner that electricity avoided costs are used. The extent to which these savings can be included in the benefits calculation is addressed in section 2.3 on attribution.

The TRC test requires an analysis over the life-cycle of the CDM measure. To accommodate this, long-term projections of avoided costs are required. Also, any CDM measures included in the analysis must have equipment life estimates along with estimates of savings and costs.

Not all of the avoided cost components and sub-components will be relevant for evaluating a particular CDM measure or program. For example, a program designed to shift load during peak hours may have little impact on annual energy use. Each potential CDM measure or program must be examined carefully to determine which types of loads will be avoided and which avoided costs apply.

Estimating the electrical avoided costs applicable to each customer class requires a number of analytical steps:

1. estimate marginal generation costs of capacity and energy;
2. estimate marginal transmission costs;
3. estimate marginal distribution costs;
4. determine the appropriate costing periods; and
5. attribute marginal costs to the costing periods.

Marginal costs studies typically involve detailed analyses starting with an understanding of the current costs for generation, transmission and distribution. Marginal costs have been developed for both capacity and energy. Capacity costs accommodate the costs of building and maintaining new generating plants, transmission and distribution systems to meet increases in peak demand. Energy costs measure the additional fuel and variable operating costs required to produce an extra kWh of energy. Energy costs can fluctuate on an hourly basis depending on the load level being served and the types of generating resources available in the market.

For Ontario, avoided costs have been developed for seasonal peak, mid-peak and off peak as well as for generation and transmission capacity. The report entitled "Avoided Cost Analysis for the Evaluation of CDM Measures" (Avoided Cost Study) filed with the Board by Hydro One Networks Inc. on June 15, 2005 is to be used in assessing CDM technologies, programs and portfolios for TRC

analysis. Hydro One also submitted a preliminary evaluation of their distribution system capacity avoided costs. A copy of the submission is available on the Board's Web Site at:
http://www.oeb.gov.on.ca/documents/dcdm_hydro_acar_170605.pdf

1.2.1 Instructions on Using the Avoided Cost Analysis for the Evaluation of CDM Measures

The Avoided Cost Study consists of a set of avoided costs including seasonal and time adjusted energy and generation and transmission capacity. Distributors are expected to use these avoided costs in performing TRC test cost effectiveness analysis.

Distributors should use the values provided in Table 21 of the Avoided Cost Study for energy, generation and transmission capacity avoided costs. Distributors should also use the values provided by Hydro One in Attachment B for the value of distribution system capacity avoided cost. Where a distributor wishes to use a different value for the distribution system capacity avoided cost, they must provide evidence supporting the variation.

Distributors should include the value of the avoided capacity costs to those projects which reduce load during system peaks. Since the Ontario load profile is summer peaking, only those measures which reduce load during the summer shall apply the avoided cost of system capacity.

1.2.2 Losses on the Distribution System

The Avoided Cost Study includes, in the energy avoided costs, a gross up for marginal losses on the transmission system. The Avoided Cost Study does not include a gross up for losses on the distribution system. While the Board recognizes that losses vary from distributor to distributor, for the purposes of cost effectiveness assessments distributors should use the industry average losses on the distribution system of 4%.

1.2.3 Electrical Energy and Demand Savings

The benefits in the TRC test are driven by the annual energy (kWh/yr) and demand (kW) savings. Energy and demand savings are often calculated at the technology level and are commonly referred to as "prescriptive" savings estimates. For programs that rely on prescriptive savings estimates, savings are calculated by multiplying the per unit (i.e. single technology) savings with the number of units installed.

Savings and technology costs must be defined relative to a frame of reference or "base case". To accurately specify the impacts of any given technology, the analyst must know what would have happened in the absence of the technology.

This represents the frame of reference or base case for the analysis. In practice, specifying savings relative to a frame of reference can be simply characterized by the three general decision types:

- new;
- replacement; or
- retrofit.

Table1.1 shows how the frame of reference assumption can dramatically alter the energy savings estimates. The example assumes that a LDC may wish to offer a program targeting *replacement* of old refrigerators with Energy Star™ refrigerators, or may offer a program that targets the complete *removal* of old refrigerators.[7]

Table 1.1: Example of Replacement and Removal Programs

Decision / Program	Existing Equipment	Base Case	Equipment	Savings
a) Replace old refrigerator with a new one	1960's vintage refrigerator using 1,500 kWh/yr	Standard refrigerator using 514 kWh/year	New Energy Star refrigerator using 440 kWh/yr	Base Case – Energy Star 514 – 440 = 74 kWh/yr
b) Retire and remove old refrigerator	1960's vintage refrigerator using 1200 kWh/yr	Keep using existing refrigerator		1200 kWh/yr

In this example, depending if the old refrigerator is replaced or completely removed (i.e. different base cases), there is a significant difference in the savings estimates.

a) In the case of the replacement, the LDC must estimate the energy use for both the "base case" equipment (i.e. the standard refrigerator) and the Energy Star™ higher efficiency refrigerator. In this case, the base case refrigerator uses 514 kWh/yr while the energy efficient refrigerator uses 440 kWh/yr. Since the program targets the installation of an Energy Star™ refrigerator over the base case option, the difference of 74 kWh/yr is the appropriate savings estimate for the program.

b) For the removal program there is no replacement with either a base case or energy efficient model. Since the program encourages the removal of the old refrigerator, the appropriate savings estimate is 1200 kWh/year.

Load impacts must be defined in a manner consistent with other assumptions in the CDM program assessments. Impacts must be calculated over the same time

[7] Where the unit would be the second refrigerator in the home.

horizon used in the program design and for the same costing periods used in defining the marginal costs. Impacts must also be consistent with the base case option used to measure incremental costs (see 1.3.1 - Equipment Costs).

1.2.4 Equipment Life

In the TRC analysis, equipment life is used to determine the time period over which the Net Present Value analysis is carried out. The benefits (i.e. energy and load savings) from an energy efficient piece of equipment are assumed to persist for the life of the equipment. Equipment life is estimated based on the nature of the equipment and an assumed usage pattern. The Assumptions and Measure List in this Guide provides a number of energy efficient equipment types and their estimated equipment lives, along with the energy and load savings and cost estimates.

An important consideration when assessing equipment life is the potential difference between the energy efficient equipment and the "base case" equipment that is being replaced. A simplifying assumption is that the energy efficient equipment lives are the same as the base case and for many cases this will be true. However, there are some technologies (such as lighting) where the energy efficient equipment may have a much longer life than the base case equipment. For example, a compact fluorescent bulb has an equipment life of up to 10,000 hours and would replace an incandescent bulb which has an equipment life of 1,000 hours. To accommodate this difference in the TRC analysis, the savings are assumed to persist for the entire 10,000 hours and the incremental cost must be adjusted to reflect the avoided purchase of 10 incandescent bulbs. This has the effect of enhancing the cost effectiveness of the compact fluorescent bulb measure. The cost data provided in the Assumptions and Measures List reflect this adjustment for technologies where it is appropriate.

1.3 Costs

This section discusses how costs, such as those provided in the Assumptions and Measures List in Part 2 are derived.

The TRC includes two types of CDM costs:

(1) equipment costs; and,
(2) program costs.

1.3.1 Equipment Costs

Typically in CDM programs, equipment costs are paid by the participant/customer. Customer equipment costs (sometimes termed "Participant costs") are the costs to purchase the more efficient equipment. They include both capital and operating and maintenance (O&M) costs associated with the

CDM program. It is important to note that the TRC test is not sensitive as to who (LDC or customer) pays the cost of the equipment.

Customer costs can be incremental or full cost depending upon the nature of the energy efficiency investment decision. Incremental equipment costs are defined as the cost of the energy efficient technology above the base case technology. In the same way that the base case is important for specifying the savings, it is also important for specifying the cost of the energy efficient equipment. For example, in a replacement scenario, the cost of the energy efficient technology is typically incremental. In a retrofit or discretionary investment case, the cost of the energy efficient technology would be the full cost of the equipment.

Equipment costs, whether paid by the customer or the LDC, including purchase and installation, must always be defined relative to a base case. It is not enough to know the installed cost associated with the energy efficient equipment used in the program. To calculate the impact of the program, the cost of the equipment that would have been purchased in the absence of the program, the base case, must also be known. The appropriate specification of incremental cost for use in the TRC analysis is the difference between the base case and the energy efficient purchase. Table 1.2 uses the same refrigerator example as in section 1.1 to show how the costs will vary depending upon the base case assumption.

As in the case of savings, there are typically three generic categories for specifying equipment costs, representing the type of investment decision:

- new;
- replacement; or,
- retrofit.

Table 1.2: Understanding Incremental Costs for TRC Analysis

Decision / Program	Baseline Equipment	Equipment Cost	Cost[8]
Replace old refrigerator	1960's vintage refrigerator using 1200 kWh/yr	Base Case refrigerator: $1,000 Energy Star refrigerator: $1,070	"Energy Star" – Base Case fridge $1,070 – $1,000 = $70
Retire and remove old fridge	1960's vintage refrigerator using 1200 kWh/yr	$0	Removal fee estimated to be $100

Table 1.2 shows two scenarios a) replacement and b) removal as in Table 1.1.

[8] Costs are provided for illustrative purposes only. Actual costs for the equipment will vary.

a) The replacement scenario requires knowledge about both the cost of the base case equipment and the energy efficient equipment. The cost to be used in the TRC analysis is the difference between the two.

b) For the refrigerator removal scenario the only costs of the program are those for removal and disposal.

The information sources for equipment costs will vary. For residential equipment, retail store prices are appropriate sources for many technologies including lighting, appliances and "do-it-yourself" water heater or thermal envelope upgrades. It is common practice to specify an average price based on a sample of retail prices. For commercial and industrial equipment cost data can be more complicated to acquire due to limited access and confidentiality concerns. For larger "custom" projects, invoices or purchase orders may be necessary to support the cost estimate.

Equipment that requires O&M expenditures is often not incremental (i.e. those costs would have been incurred in the base case anyway). However, if the energy efficient equipment requires significantly more maintenance than its less energy efficient counterpart, the incremental O&M costs need to be factored into the TRC analysis. There will be exceptions and a proper TRC analysis should incorporate these.

1.3.2 CDM Program Costs

From the perspective of the TRC test, CDM program costs are those incurred by the LDC. These costs include the marketing and support costs associated with delivering the CDM activity. Participant or customer incentive costs, which are considered transfers in the TRC test are not included in the analysis. This section also discusses the issue of customer incentives for CDM programs. LDC costs typically cover a number of activities such as marketing and advertising, consulting, channel support, monitoring and evaluation.

There are five major categories of LDC costs:

i. development and startup;
ii. promotion;
iii. equipment and installation;
iv. monitoring and evaluation; and
v. administration.

In practice, all of these costs can be expected for programs that electric LDCs in Ontario might be considering.

i. Development and startup costs

Development and startup costs are different from on-going operating costs. For example, initial costs may be incurred to train LDC staff in the use of the equipment or techniques inherent in a program and usually occur at the early stages of the program's life. Costs of developing CDM plans and procedures are often concentrated in the early program years. In general, start-up costs are only a small component of the total costs in the life cycle of a CDM program.

ii. Promotion costs

Promotion costs may be incurred to educate the customer about a CDM program and will vary by program type and level of promotional effort. The cost of promotion depends on the method employed, the market segment and the CDM measures promoted. The best methods for program promotion involve trade-offs between increases in promotion costs and expected increases in participation.

Table 1.3 Some Methods of Promotion

Type of Contact	Tactics
Personal contact with LDC representative	Telemarketing Customer service campaign Door-to-door campaign
Other direct LDC contact	Bill stuffers Direct Mail
Mass media	Print/flyers Television/Radio
Trade allies	Equipment vendors Equipment installers

Note on LDC Costs for Customer Incentives

Since the TRC test is an evaluation of a CDM program at a societal level, it is not sensitive to who (LDC or participant) pays the equipment costs of a CDM initiative (i.e. society benefits regardless of who pays for the energy efficient equipment). The appropriate costs to be included in the TRC analysis are the equipment and program delivery costs. Therefore, incentive payments from the LDC to a customer for participation in a program are not a component of the TRC analysis. The incentive merely represents a transfer between two potential purchasers of the equipment.

Many CDM programs involve some form of transfer payment (i.e. incentive) between LDCs and participants. They are generally characterized as follows:

- rebates;
- loans and leases;

- shared savings arrangements; or,
- participation fees.

While incentives primarily serve to improve the economic attractiveness of CDM investments for the customer, they also serve to increase customer awareness of the programs. As well, an incentive creates a specific paper trail that LDCs can use as part of their tracking and evaluation activities.

Utilities are free to design incentive schemes specific to their customers. Often, payback criteria or rebates are used in incentive design. This approach is often more important to commercial and industrial customers. For these customers, many utilities favour an approach that lowers the payback to a specific threshold, or ensures that incentives are only applied to projects with paybacks above a certain threshold.

An alternative approach is to gauge rebate levels relative to the incremental capital cost of the CDM technology compared to a standard technology that would have been installed in the absence of the program. Rebates are often set at some percentage of incremental cost. In practice, those percentages vary from a fraction of the incremental cost to completely off-setting incremental cost.

iii. LDC Equipment and Installation Costs

LDC equipment and installation costs include the costs of any LDC devices needed to operate the programs such as specialized software or tools as well as any CDM measures directly installed by the LDC such as load controllers.

iv. Monitoring and Evaluation Costs

This section focuses only on the cost to the LDC to monitor and evaluate a CDM portfolio. A detailed discussion on the nature of tracking, monitoring and evaluation is provided in Section 3.

There are two broad categories of evaluation activity: impact evaluation and process evaluation. Impact evaluation focuses on the specific impacts of the program – for example, savings and costs. Process evaluation focuses on the effectiveness of the program design – for example through the delivery channel approach. The costs associated with each of these activities are program costs that need to be included in the TRC analysis. Some of these costs will be assigned directly to a specific program or programs, while a portion of the costs are more appropriately assigned across all programs (i.e. at the CDM portfolio level).

Monitoring and evaluation costs are incurred for systems, equipment and studies necessary to track measurable levels of program success (participants, load impacts and costs) as well as to evaluate the features driving program success

or failure. It is important to develop the necessary tracking systems at the time of program design. At a minimum, the tracking system must collect information on the key components that drive the TRC test, including:

- number of participants/installations;
- energy and seasonal demand savings;
- cost of equipment; and,
- LDC program and incentive costs.

Prescriptive load savings and cost values for most equipment are listed in the Assumptions and Measures List of this Guide.

To facilitate evaluations of CDM programs and results, LDCs must have clearly documented "paper trails" on the elements that drive a savings claim.

v. Administrative costs

Administrative costs are generally the costs of staff who work on CDM activities. These costs are often differentiated between support and operations staff. Support staff costs are considered fixed costs or "overhead" that occur regardless of the level of customer participation in the programs. Operations staff costs are variable, depending on the level of customer participation. LDCs must include all staff salaries that are attributable to CDM programs as part of the costs in the TRC analysis.

For an accurate TRC assessment, the LDC must ensure that all non-incentive costs associated with designing, operating and tracking the programs are accounted for in its TRC analysis.

1.3.3 Categorizing Costs

As a matter of practice and for ease of performing cost effectiveness testing, many utilities categorize costs as either direct or indirect.

Direct costs can be clearly allocated to a particular program and may include marketing, consulting and field staff costs among others. Direct costs factor into the program level cost effectiveness analysis. Indirect costs can not be easily allocated to any particular program. These costs include overhead, administration and monitoring and evaluation. Indirect costs are typically incurred at the portfolio level and included in the portfolio cost effectiveness analysis.

2.0 Adjustment factors in the TRC Test

In performing a TRC analysis, several adjustments must be made to the benefits side of the equation. These adjustments include:

- free ridership of participants;
- attribution of the benefits, and
- persistence of the measures.

2.1 Free Riders

Free rider adjustments are one of the key components for the TRC test. The standard definition of a free rider is "a program participant who would have installed a measure on his or her own initiative even without the program".[9] Free ridership assessment is critical for the accuracy of cost-effectiveness evaluations.

Costs and benefits associated with free-ridership should be assessed as part of the TRC analysis. In determining overall savings, these participants are excluded from the benefits attributed to the program. The equipment costs associated with these participants is similarly excluded from cost side of the equation.[10] However, it should be noted that all program costs associated with free riders must be included in the analysis. As such, programs that have high free ridership are self-evident in the marketplace (i.e. they do not rely on a LDC subsidy) and therefore are less cost effective for the LDC to pursue since the program costs are included in the TRC calculation while the benefits are not. Free rider estimates are established through market studies and initial values have been provided in the Assumptions and Measures List.

2.2 Attribution

A fundamental issue for the evaluation of CDM programs is whether the effects observed after the intervention occurs can be attributed to the intervention under evaluation (otherwise known as causality).

Since it can be expected that there will be multiple delivery points of CDM, including other electric LDCs, gas LDCs, electric retailers, gas marketers, the Ontario Power Authority and various levels of government, it is important to understand the Board's guidelines for the attribution of benefits especially in light of a potential claim for shareholder incentive.

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[9] Violette, Daniel M. (1995) Evaluation, Verification, and Performance Measurement of Energy Efficiency Programs. Report prepared for the International Energy Agency.

[10] Eto, J. (1998) Guidelines for Assessing the Value and Cost-effectiveness of Regional Market Transformation Initiatives. Northeast Energy Efficiency Partnership, Inc.

This section outlines the guidelines for attributing benefits between OEB regulated CDM delivery utilities and for savings associated with other resources. While attribution is not a true adjustment to the TRC test, this issue is important for those utilities that plan on seeking a shareholder incentive. The Board advises LDCs that they are allowed to claim 100% of the benefits associated with a CDM program in which they jointly market and deliver the program with a non-rate regulated third party.

2.3.1 Attribution Guidelines for CDM Programs

The formula for determining savings associated with a CDM program is:

Savings = (UATES) x (NUD) x (1-FRR)

where;

Savings – kWh/yr and/or other resource measure;

UATES – Unit Annual Total Energy Savings

NUD – Number of Units Delivered

FRR – Free Ridership Rate

In order to estimate the savings attributable to the LDC an attribution rate is added to the previous formula to get:

Attributable Savings = (UATES) x (NUD) x (1-FRR) x (AR)

where;

AR – Attribution Rate

In most cases, the attribution rate will be 1.0, indicating that the LDC should claim in its TRC calculation all of the benefits associated with the CDM program.

Where a given CDM program is targeted at an end use that has two or more energy sources in the marketplace, a variable must be added to the formula to calculate the primary energy savings as follows:

Attributable Savings = (UATES) x (NUD) x (1-FRR) x (AR) x (EUMS)

where;

EUMS – End-Use Market Share

In this instance the savings associated with any energy sources must be adjusted to the extent the energy source is used for a given end use. A common example of this type of adjustment would be a low-flow shower head program. Resource savings associated with this program must be adjusted, by the EUMS

term, to the extent that the resource is used for the given end use (i.e. electrical versus gas hot water heating).

The following discussion consists of the Board Guideline on the attribution of benefits between regulated delivery utilities.

Case 1- Programs delivered jointly by LDCs with single energy savings (i.e. electricity):

In this case, several LDCs work together to jointly market and deliver a CDM program. Each participating LDC is allowed to claim the benefits associated with the program (electricity and water) in their service area. The determining factors are the location of the participants and the benefits associated with the program. No consideration is given to the proportional amount of funds that each participating LDC invested in the program.

Therefore, in this case, the Attributable Savings would be:

Attributable Savings = (UATES) x (NUD_{SA}) x (1-FRR) x (AR)

NUD_{SA} - number of units delivered in a LDC's service area.

AR = 1

Case 2 – Multi energy savings in cross sector (gas and electricity) jointly delivered CDM:

In this case, a gas and electric LDC jointly market and deliver a CDM program. Each participating LDC is allowed to claim all of the benefits associated with the CDM program of the energy type they distribute regardless of the investment amount (i.e.: gas LDCs would claim the gas savings and electricity LDCs would claim the electricity demand and energy savings). Other benefits, such as water savings, need to be allocated between the gas and electric LDC partners proportionally based on the dollar value of TRC savings of that program (i.e. where electricity savings represent 60% of the TRC savings of a program, the electric LDC will claim 60% of the water savings).

Case 3 - Multi energy savings-individually delivered DSM/CDM programs:

In this case, a LDC works independently to market and deliver a CDM program. The LDC's program may have energy savings additional to the primary energy savings targeted by the program. Common examples of these are Low Flow Shower Head and Programmable Thermostat programs. In these cases, the

benefits of the programs will be electricity demand and energy as well as other energy savings. Therefore, the total savings formula would be:

$AS_{primary\ energy} + AS_{other\ energy}$

$AS_{primary\ energy}$ = (UATES) x (NUD) x (1-FRR) x (AR) x (EUMS)

$AS_{other\ energy}$ = (UATES) x (NUD) x (1-FRR) x (OEAR) x (1 - EUMS)

where:

OEAR – alternative energy attribution rate

In this case, the OEAR would be set to 1.0, indicating that the LDC delivering the CDM initiative could include all of the benefits associated with the other energy savings in the TRC calculation.

2.4 Persistence

Persistence is a measure of how long a CDM measure is kept in place by the customer. Persistence is important for all energy efficiency interventions as a lack of persistence can have very significant effects on overall net program savings estimates. For example, if an energy efficient measure with a 15-year lifetime is removed after only two years, most of the savings thought to result from that installation will not materialize.

There is a compelling argument for accounting for persistence in the assessment of CDM cost effectiveness, especially for measures which are easily retrofitted such as compact fluorescent light bulbs. However, at this time, LDCs should assume 100% persistence in assessing CDM cost effectiveness unless otherwise updated by the Board.

3.0 Tracking and Measuring CDM Program Results

This section focuses on the requirements for tracking and measuring the effects of CDM programs.

Requirements for three types of programs are examined:

1. Direct acquisition programs are programs that have clear causality between LDC activity and energy savings.
2. Market support/outreach programs are programs in which the LDC supports outreach or educational efforts which generally promote the energy efficiency message, but where savings are indirect and it is difficult to see a clear cause and effect relationship.
3. Custom projects are programs that are generally large or complex in nature and often include a variety of individual measures and targeted at a specific customer.

3.1 Tracking of Direct Acquisition Programs

Direct acquisition programs are relatively easy to track and measure. Tracking requirements represent one of the administrative functions of program delivery. While the specifics will vary for each type of program, there is a need to show clear cause and effect between the LDC's activities and the customer's load reduction. In direct acquisition programs, this is often precipitated by the processing of a participant incentive. LDCs will need to have systems for collecting of relevant information for each program, including:

- technology type;
- number of installations;
- savings estimates;
- equipment cost estimates;
- customer address or location;
- delivery channel; and,
- incentive amount.

It may not be feasible to collect all information for all programs. For example, a program delivered by a retailer that relies on in-store coupons will likely not have the means to track who actually used the coupons and received the product(s). However, the retailer can be expected to track information about the number of coupons turned in, and the LDC's tracking system could then calculate the resulting cost to the LDC. With this information, the LDC can then calculate the savings and equipment cost and combine the information with equipment life, free rider estimates and program costs - resulting in both a tracking report and the requirements for the TRC analysis.

In the case of a program delivered by a third party, the tracking requirements will include reports that the delivery partner provides to the LDC. These reports should provide details on the customer visits, including address and equipment installed.

3.2 Tracking of Market Support Programs

Load reductions from CDM activities related to training, public outreach and the general provision of information on efficient energy use are difficult to track, measure and establish clear causality. Since market support programs typically do not result in direct demand or energy savings, other assessment criteria must be used to assess their validity. Table 3.1 provides a sample of potential tracking activities that might accompany the delivery of these programs. Each market support activity should attempt to have at least one metric.

Table 3.1. Sample Market Support Assessment Criteria

Support	Metric	Additional Information
Web-site calculator	Number of hits	Survey re: usefulness of website
Training sessions for contractors	Number of sessions Number of attendees	Survey re: specific activities undertaken by attendees
Home shows	Number of giveaways	Survey re: energy efficient appliances
Design workshops	Number of professional attendees	Surveys re: design activities

3.3 Custom Projects

For a custom project (i.e. a LDC facilitates a complete audit and upgrade of a facility) tracking requirements will include the type of equipment that was installed, the related savings and equipment cost and any LDC support costs. Since custom projects usually involve specialized equipment, savings estimates must be assessed accordingly. It is expected that each custom project will incorporate a professional engineering assessment of the savings. This assessment would serve as the primary documentation for a savings claim.

A special audit program must be implemented for custom projects. The audit should be conducted on a random sample consisting of 10% of the large custom projects; and the projects should represent at least 10% of the total volume savings of all custom projects. The minimum number of projects to audit would be 5 and the free rider rate for these projects would be 30%. The audit will focus on verifying the equipment installation and estimates of savings and equipment cost. The audit will also examine the role of the LDC in delivering or facilitating the project.

4.0 How to Calculate TRC

This section provides details of how to perform a TRC analysis with examples for a single technology calculation, a program calculation and an entire portfolio of programs.

As discussed earlier, a LDC's CDM portfolio is the highest level envelope incorporating all of the costs not captured at the technology and program level. Therefore, a CDM portfolio consists of set of cost effective CDM programs. Similarly, a CDM program is designed around a given cost effective measure or

technology.[11] Cost effectiveness screening is assessed at each level of a LDC's CDM initiative.

The TRC calculation relies on estimates of:

- avoided cost;
- demand and energy savings;
- equipment cost;
- LDC program costs;
- equipment life;
- free ridership.

These estimates are used in a standard NPV calculation that relies on a discount rate to express a value for future streams of money and to determine a cost effectiveness result in current dollars.

4.1 Calculating the TRC for a Single Technology – Technology Screening Analysis

In its simplest form, the single technology screening analysis calculates the cost effectiveness of a single piece of equipment or technology based purely on its energy efficiency characteristics, its cost and equipment life. This screening analysis is the initial step in considering technologies for inclusion in a CDM program.

To perform the technology screening analysis, the required elements are:

- estimate of per unit savings (kW and kWh) by period;
- estimate of equipment cost; and
- expected equipment life.

This is a simple cost benefit analysis of the technology on a single unit basis.

Calculating the benefits: The benefits are expressed as the product of the per unit savings (in kW and/or kWh) and the avoided costs. This calculation is done for every year of the life of the equipment. These values are then discounted and summed to express the benefits as a single $NPV_{benefits}$.

Calculating the costs: The equipment cost is the cost of the technology, expressed as either its full or incremental cost. In most cases, the cost of the technology is incurred at the beginning of the initiative and no further costs are incurred over the life of the equipment (i.e. a CFL bulb). However, where the energy efficient equipment has ongoing maintenance costs incremental to the base case alternative, these costs should be included in the analysis and

[11] An LDC may wish to undertake programming on non-cost effective technologies in the form of pilot programs or test efforts as part of a market support or market research activity. The rationale for these activities must be clearly identified.

discounted appropriately. Once this calculation is performed, it is expressed as a single NPV_{costs}.

Example 1: Technology Screening Analysis

In this example, a compact fluorescent light bulb replaces a standard incandescent bulb in a residential application.

Measure:	Replace 60 W incandescent bulb
Technology:	15 W Compact fluorescent bulb
Savings:	104 kWh/yr
Equipment Cost:	$2.00
Equipment Life:	4 years
Discount rate:	7.5%

The calculations and tables in Appendix B show that the net present value per unit is $23.75.

The results of this technology screening analysis indicate that at the technology level, the proposed measure is cost effective and could be promoted to the program screening analysis for further evaluation.

Example 2: Technology Screening Analysis

In this example, a low flow showerhead replaces an inefficient showerhead in a standard residential application. There are both electricity and water savings that are assessed in the TRC analysis. The savings, equipment cost and equipment life are provided in the Assumptions and Measures List.

Measure:	Install low flow showerhead
Technology:	9.4 litre/minute low flow showerhead
Electricity Savings:	545 kWh/yr
Water Savings:	26,800 litres/year or 26.8 m^3/yr
Equipment Cost:	$7.00
Equipment Life:	12 years
Discount rate:	10%

The following TRC benefit calculation is identical to Example 1 except that the benefits associated with water savings are incorporated.

The calculations and tables in Appendix B show that the $NPV_{Technology}$ is $469.00 per unit.

4.2 Calculating the TRC for a Program – Program Screening Analysis

Once a measure has passed the technology screening analysis, the analyst may wish to design a program that uses the technology. The program screening analysis combines the results of the individual technology analysis with the key program components, including number of participants, free ridership rates and direct LDC program costs. The program screening analysis repeats the same approach as defined in section 4.1 with the inclusion of the adjustment factors to assess the measure at the program level.

Example: Program Screening Analysis

Using the technology from Example 1 above, a program screening analysis would incorporate the following adjustments, given the following assumption:

Participant number:	10,000
Free rider rate:	10%
Direct program cost:	$75,000*
Equipment cost	$20,000

Therefore, the $NPV_{Program}$ is as follows:

NPV of Program Benefits	237,500
NPV of Program Benefits (net of free riders)	213,750
Direct Program Costs	(75,000)
Equipment Cost (Participant costs net of free riders)	(18,000)
Program $NPV_{Program}$	120,750

Using the technology from Example 2 above, a program screening analysis would incorporate the following adjustments, given the following assumptions:

Participant number:	1,000
Free rider rate:	10%
Direct program cost:	$50,000*
Equipment cost:	$7,000

Therefore, the $NPV_{Program}$ is as follows:

NPV Program Benefits	469,000
Program NPV net of Free Riders (1-FRR)	422,100
Direct Program Costs	(50,000)
Equipment Cost (net of free riders)	(6,300)
Program $NPV_{Program}$:	365,800

* Costs are for illustrative purposes only.

4.3 Calculating the TRC for a Portfolio - Portfolio Screening Analysis

Once the LDC has screened all of its programs and is comfortable with the program designs, the overall cost effectiveness of the portfolio needs to be tested. To do this, the LDC will sum the program TRC results and then allocate administrative and any market support costs (indirect costs) to the entire portfolio. Administrative costs include overhead, monitoring and evaluation costs and administration costs associated with the delivery of the overall CDM portfolio. This roll-up value represents the TRC result for the entire CDM programming activity.

Example: Portfolio Screening Analysis

Assuming a LDC planned to deliver only the two programs discussed above; the following consists of a theoretical portfolio screening analysis.

Assuming a LDC has indirect costs of administration, market support, overhead and monitoring and evaluation of $200,000.* The NPV of the portfolio would be as follows:

Program 1 $NPV_{Program}$:	120,750
Program 2 $NPV_{Program}$:	365,800
NPV of Total Indirect Costs	(200,000)
NPV_{TRC}	**286,550**

Therefore, the NPV_{TRC} of this portfolio is $286,550.

4.4 Using TRC Analysis for Post Program Evaluation

The TRC calculation done at the end of a program year follows exactly the same approach using the "actual" information collected as part of the tracking and reporting exercises as opposed to estimates.

* Costs are for illustrative purposes only.

5.0 Assumptions and Measures List

The Assumptions and Measures List data were developed using secondary research, augmented by expert input as required. All data points were cross-referenced with a minimum of two sources. Where possible, recent Canadian experience and data was used. All savings data were based on an understanding of average electricity loads in typical applications in each sector. Cost data were collected from a variety of sources including retailers and distributors. Free rider values are also provided for all measures.[12]

[12] While it is recognized that free ridership is appropriately applied at the program level, the Assumptions and Measures List provides an estimate to facilitate cost effectiveness analysis.

Appendix A: Glossary of Terms

Avoided Equipment Costs

The avoided equipment cost or base case equipment cost refers to the cost of the equipment that the customer would have installed in absence of the program. These costs cover all the out of pocket expenses that the customer would have incurred for the standard equipment as compared to the high efficiency equipment.

Base Case Technology

Energy impacts must always be defined relative to some frame of reference. The base case technology variable represents the piece of equipment or technology that is being replaced by a more efficient technology. The application of a base case technology can vary, for example, in the case of a CDM program consisting of a residential programmable thermostat; the base technology would be no programmable thermostat. In the example of a program consisting of a high efficiency furnace, the base case equipment would be the homeowner's current furnace. At a minimum the base case technology must be equal to or more efficient that the technology benchmarks mandated in energy efficiency standards.

Base Annual Energy Usage

Energy impacts are what drive the calculations for the supply cost savings and revenue impacts. The base case technology energy usages are used to determine the level of energy savings relative to the more efficient technology. It is important to note that the energy usage is expressed in terms that relate to the system supply costs. For example, there are typically several costing periods at the system supply level; winter vs. summer, peak vs. off-peak.

Base Year

The base year refers to the first year of the program analysis. This year is typically set to the current calendar year or the year of the LDC's Conservation Demand Management (CDM) portfolio.

Discount Rates used for CDM Cost Effectiveness Analysis

Discount rate refers to the economic rate of interest that is used to convert a future stream of dollars into current dollars. The resulting value is often termed Net Present Value or NPV. In terms of a conservation or demand management program, the discount rate is used to compare current and future demand and energy savings with the costs of a CDM program investment.

Efficient Technology

The efficient technology variable refers to the more energy efficient technology being used to replace the base case technology.

Efficiency Technology Energy Usage

The efficient technology energy usage represents the level of energy consumption being used by the more efficient technology. As in the case of the base case technology, the consumption must be expressed in terms that relate to the system supply costs. For example, there are typically several costing periods at the system supply level; winter vs. summer, peak vs. off-peak.

End –Use Market Share

The end-use market share is the market share of the end-use (i.e. electric or gas hot water heaters) addressed by a measure (i.e. low flow shower heads) in the sector (i.e. electricity or gas) to which the measure is targeted.

Equipment Costs

Customer equipment costs refer to all out of pocket expenses incurred by the customer as a result of the high efficiency equipment. These costs are before any rebate has been applied. Cost categories include:

- Equipment costs, including provincial sales tax and G.S.T. and installation.
- Operation and maintenance costs
- Any removal costs (less salvage value)
- Any other costs directly related to the customer's equipment choice (i.e. engineering consultation).

Equipment Life

The equipment life variable represents the number of years that the more efficient equipment installed is assumed to produce energy savings. In most

cases, the full life of the efficient equipment is applied; however, there may be cases in which the efficient equipment may be installed prior to the end of the useful life of the base case equipment. In such cases, using a number different from the manufacturers' equipment life expectancy is appropriate.

Free-rider

A free rider is a program participant who would have installed a measure on his or her own without the CDM program. This participant simply uses the program to offset the cost of installing or undertaking the energy efficient initiative.

Incentives

Incentives are any form of financial transfer from the LDC to the program participant to encourage program participation. The most common form of incentives is a rebate which is designed to help off set the cost of purchasing a more expensive piece of equipment.

Avoided Costs

Avoided costs are the marginal costs that are avoided by not producing and delivering the next unit of energy to the customer. Marginal costs (or avoided costs) include generation, transmission and distribution costs. They measure the expected change in the systems total costs due to a decrease or increase in load and are calculated using either a short-run or long run perspective.

Measure

CDM programs are most often concerned with the use of equipment (i.e. particular types of water heaters, appliances), technologies (i.e. cycling, timing, heated water storing) or processes / procedures (i.e. equipment servicing / maintenance / tune up) for the purpose of promoting energy efficiency. The terms 'equipment' and 'technology' often can be used interchangeably.

When the application of a technology, type of equipment, or procedure is used to replace another technology or type of equipment, or procedure it is referred to as the 'measure'. A measure is therefore, an action to change one piece of equipment for another.

Program Participants

The number of participants or installations expected for the program. Typically specified on an annual basis, this value is multiplied by the per unit impacts and the free ridership level to generate the total savings for the program.

Third Party Rebates

This variable refers to any dollar discounts or rebates offered to the customer by any other party other than the LDC (i.e. government or manufacturer) for the purchase of an energy efficient technology. Third party rebates are not considered in the Total Resource Cost Test, as it is considered a benefit to the customer and a cost to the third party and therefore, cancel each other out.

LDC Costs

There are some broad categories of expenditure that must be considered when developing a CDM portfolio of programs. These categories include:

- Program development and start up costs
- Program administration
- Promotion and advertising
- Capital Equipment
- Monitoring and tracking
- Evaluation

Appendix B: Sample Calculations and Tables

Number	Efficient Equipment & Technologies	Base Equipment & Technologies	Decision Type	Annual Operating Time hrs/yr	Base Annual Energy (kWh/yr)	Efficient Energy Use (kWh/yr)	Annual Energy Savings with Upgrade (kWh/yr)	On Peak (kW)	EE Technology Life	Incremental Equipment Cost $	Lifespan hrs	Free Ridership	Energy Savings Winter Peak (kWh)	Energy Savings Winter Mid (kWh)	Energy Savings Winter Off Peak (kWh)	Energy Savings Summer Peak (kWh)	Energy Savings Summer Mid (kWh)	Energy Savings Summer Off Peak (kWh)	Energy Savings Shoulder Mid (kWh)	Energy Savings Shoulder Off (kWh)
	Interior Lighting - Fluorescent																			
1	2 - T8 32W (58 W reflectorized w/EL ballas	4 - T12 34W (156W 4 Lamps w/2 magnetic ballasts	Ret./Repl.		1014	377	637	0.34	3	$93	20000	10%	44	50	113	38	57	118	91	118
2	4 - T8 32W (112W) 4 Lamps w/EL ballas	2 - T12 75W (184W) 8 HO Lamps w/1 magnetic ballas	Ret./Repl.		1196	728	468	0.25	3	$69	20000	10%	32	37	84	28	42	87	70	87
3	1- T8 32W (38W) w/EL HBF ballast	2 - T12 34W (78W) 4 lamps pendant mount 1 EM ballas	Ret./Repl.		507	247	260	0.14	3	$75	20000	10%	18	20	46	15	23	48	39	48
	Interior Lighting - Warehouse & Plant																			
3	250W Metal Halide Lamp, PT	400W Mercury Vapor	Ret./Repl.		1818	1752	64	0.03	3	$245	15,000	10%	4	5	12	4	6	12	10	12
4	175W Metal Halide Lamp, PT	250W Mercury Vapor	Ret./Repl.		1710	832	878	0.47	3	$240	15,000	10%	60	69	162	52	78	163	131	163
5	200W High Pressure Sodium	400W Mercury Vapor	Ret./Repl.		1818	960	858	0.46	4	$240	24,000	10%	59	67	158	51	77	159	128	159
6	6 - T5 HO Lamps in new High Bay fixture (372W	400W Metal Halide PS High Bay	Ret./Repl.		1818	1465	328	0.18	3	$436	20,000	10%	23	26	60	20	29	61	49	61
7	100W Metal Halide fixture	4 - T12 34W (156W) 4 lamps 2 EM ballasts	Ret./Repl.		824	516	108	0.06	3	$250	12500	10%	7	8	20	6	10	20	16	20
	Interior Lighting - Exit Sign																			
8	3W LED EXIT sign	2 - 15W / 30W Incandescent EXIT Sign	Ret./Repl.		263	26	237	0.16	25	$95	220000	10%	16	19	44	14	21	44	35	44
	Compressed Air System (100 hp)																			
9	Dessicant Dryer Control Upgrade	Fixed Interval Dessicant Regenerate	Ret./Repl.		90,468	81165	14323	3.07	15	$8,000		5%	984	1125	2639	853	1280	2654	2114	2654
10	Convert to On/Off Control	Bypass or Inlet Throttle Control	Ret./Repl.		90,468	57293	38195	8.18	15	$6,500		5%	2625	3000	7037	2276	3414	7077	5636	7077

Number	Efficient Equipment & Technologies	Base Equipment & Technologies	Decision Type	Annual Operating Time hrs/yr	Base Annual Energy (kWh/yr)	Efficient Energy Use (kWh/yr)	Annual Energy Savings with Upgrade (kWh/yr)	On Peak (kW)	EE Technology Life	Incremental Equipment Cost $	Lifespan, hrs	Free Ridership	Energy Savings Winter Peak (kW.h)	Energy Savings Winter Mid (kW.h)	Energy Savings Winter Off Peak (kW.h)	Energy Savings Summer Peak (kW.h)	Energy Savings Summer Mid (kW.h)	Energy Savings Summer Off Peak (kW.h)	Energy Savings Shoulder Mid (kW.h)	Energy Savings Shoulder Off (kW.h)
	Interior Lighting - Fluorescent																			
1	4 - T8 32W (59 W with ballast) w/1 ballast	4 - T12 34W (156W 4 Lamps w/2 magnetic ballast	Ret. Repl.		1014	477	537	0.34	5	$50	20000	10%	41	53	51	35	53	51	0	106
2	4 - T8 32W (112W 4 Lamps w/1 ballast	2 - T12 75W (156W 4 HO Lamps w/1 magnetic ballast	Ret. Repl.		1156	724	869	0.25	5	$54	20000	10%	51	51	64	24	42	87	76	51
3	1 - T8 32W (59W w/1 HW ballast	2 - T12 34W (156W 4 lamps pendant mount 1 EM ballas	Ret. Repl.		700	241	283	0.14	5	$71	20000	10%	14	20	48	10	23	48	33	48
	Interior Lighting - Warehouse & Plant																			
3	250W Metal Halide Lamp, PC	400W Mercury vapor	Ret. Repl.		1816	1752	64	0.03	3	$240	15,000	10%	4			4	4	12	11	11
4	175W Metal Halide Lamp, PC	250W Mercury vapor	Ret. Repl.		1114	832	282	0.14	3	$240	15,000	10%	62	84	56	62	73	109	112	102
5	200W High Pressure Sodium	400W Mercury vapor	Ret. Repl.		1816	960	856	0.40	3	$240	24,000	10%	94	81	109	111	73	113	124	112
6	6 - T5 HO Lamps in new High Bay fixture (372W	400W Metal Halide PS High Bay	Ret. Repl.		1816	1488	328	0.16	3	$438	20,000	10%	13	24	60	38	23	61	43	51
7	1000W Metal Halide fixture	4 - T12 34W (156W 4 lamps, 2 EM ballasts	Ret. Repl.		624	514	109	0.06	3	$237	12,000	10%	1	3	10	2	5	16	15	10
	Interior Lighting - Exit Sign																			
8	5W LED EXIT SIGN	2 - 10W 30W Incandescent EXIT Sign	Ret. Repl.		350	35	315	0.14	10	$41	120000	10%	13	18	44	18	27	44	31	44
	Compressed Air System (100 hp)																			
9	Desiccant Dryer Control Upgrade	Fixed Internal Desiccant Regenerative	Ret. Repl.		61,465	47,153	14,312	3.27	15	$9,000		5%	994	1,121	2,870	803	1,095	2,824	2,538	2,824
10	Convert to On/Off Control	System w/ Inlet Throttle Control	Ret. Repl.		61,465	47,153	14,312	3.27	15	$5,000		5%	994	1,121	2,870	803	1,095	2,824	2,538	2,824

Example 1: Technology Screening Analysis

Table A. Measure Savings

Year	Measure Energy Savings (kWh)								Measure Demand Savings
	Winter			Summer			Shoulder		
	On Peak	Mid-Peak	Off Peak	On Peak	Mid-Peak	Off Peak	Mid-Peak	Off Peak	On Peak (kW)
1	15.48	7.74	20.34	0	11.75	13.95	17.46	17.685	0
2	15.48	7.74	20.34	0	11.75	13.95	17.46	17.685	0
3	15.48	7.74	20.34	0	11.75	13.95	17.46	17.685	0
4	15.48	7.74	20.34	0	11.75	13.95	17.46	17.685	0

Table B. Measure Savings Including Distribution System Losses

Year	Measure Energy Savings (kWh)								Measure Demand Savings
	Winter			Summer			Shoulder		
	On Peak	Mid-Peak	Off Peak	On Peak	Mid-Peak	Off Peak	Mid-Peak	Off Peak	On Peak (kW)
1	16.0992	8.0496	21.1536	0	12.2148	14.508	18.1584	18.3924	0
2	16.0992	8.0496	21.1536	0	12.2148	14.508	18.1584	18.3924	0
3	16.0992	8.0496	21.1536	0	12.2148	14.508	18.1584	18.3924	0
4	16.0992	8.0496	21.1536	0	12.2148	14.508	18.1584	18.3924	0

Table C. Avoided Electricity Costs

Year	Ontario Seasonal Average Avoided Energy Cost (2005 CAD$/kWh)								Avoided Capacity		
	Winter			Summer			Shoulder		Generation	Transmission	Distribution
	On Peak	Mid-Peak	Off Peak	On Peak	Mid-Peak	Off Peak	Mid-Peak	Off Peak	(2005 CAD$/kW-yr)		
	602	688	1,614	522	783	1,623	1,305	1,623	N/A	N/A	N/A
1	$0.1178	$0.0819	$0.0443	$0.1102	$0.0794	$0.0463	$0.0821	$0.0413	$0.00	$0.00	$0.00
2	$0.1186	$0.0802	$0.0430	$0.1062	$0.0757	$0.0437	$0.0775	$0.0389	$0.00	$0.00	$0.00
3	$0.1072	$0.0806	$0.0454	$0.1027	$0.0776	$0.0466	$0.0839	$0.0417	$69.32	$5.22	$0.00
4	$0.1014	$0.0698	$0.0443	$0.0947	$0.0720	$0.0431	$0.0777	$0.0393	$75.71	$5.22	$6.50

Table D. Avoided Electricity Cost Savings

Year	Nominal Savings ($)								Nominal Savings ($)		
	Winter			Summer			Shoulder		Avoided Capacity Costs		
	On Peak	Mid-Peak	Off Peak	On Peak	Mid-Peak	Off Peak	Mid-Peak	Off Peak	Generation	Transmission	Distribution
1	$1.90	$0.66	$0.94	$0.00	$0.97	$0.67	$1.49	$0.76	$0.00	$0.00	$0.00
2	$1.91	$0.65	$0.91	$0.00	$0.92	$0.63	$1.41	$0.72	$0.00	$0.00	$0.00
3	$1.73	$0.65	$0.96	$0.00	$0.95	$0.68	$1.52	$0.77	$0.00	$0.00	$0.00
4	$1.63	$0.56	$0.94	$0.00	$0.88	$0.63	$1.41	$0.72	$0.00	$0.00	$0.00

Table E. Discounted Avoided Electricity Cost Savings

Year	Discount Rate Factor	Discounted Savings ($)								Discounted Savings ($)			Total Discounted Savings
		Winter			Summer			Shoulder		Avoided Capacity Costs			
		On Peak	Mid-Peak	Off Peak	On Peak	Mid-Peak	Off Peak	Mid-Peak	Off Peak	Generation	Transmission	Distribution	
1	1.0000	$1.8965	$0.6593	$0.9371	$0.0000	$0.9699	$0.6717	$1.4908	$0.7596	$0.0000	$0.0000	$0.0000	7.38
2	1.0750	$1.7762	$0.6005	$0.8461	$0.0000	$0.8601	$0.5898	$1.3091	$0.6655	$0.0000	$0.0000	$0.0000	6.65
3	1.1556	$1.4934	$0.5614	$0.8310	$0.0000	$0.8202	$0.5850	$1.3183	$0.6637	$0.0000	$0.0000	$0.0000	6.27
4	1.2423	$1.3141	$0.4523	$0.7543	$0.0000	$0.7079	$0.5033	$1.1357	$0.5818	$0.0000	$0.0000	$0.0000	5.45

Table F. Measure Costs and Benefits

Measure Benefits	Measure Costs
25.75	2.00

Example 2: Technology Screening Analysis

Table A. Measure Savings

Year	Measure Energy Savings (kWh)								Measure Demand Savings	Annual Water Savings
	Winter			Summer			Shoulder			
	On Peak	Mid-Peak	Off Peak	On Peak	Mid-Peak	Off Peak	Mid-Peak	Off Peak	On Peak (kW)	litres/yr
1	37.48	42.84	100.50	32.50	48.75	101.06	81.26	101.06	0.04	26,800
2	37.48	42.84	100.50	32.50	48.75	101.06	81.26	101.06	0.04	26,800
3	37.48	42.84	100.50	32.50	48.75	101.06	81.26	101.06	0.04	26,800
4	37.48	42.84	100.50	32.50	48.75	101.06	81.26	101.06	0.04	26,800
5	37.48	42.84	100.50	32.50	48.75	101.06	81.26	101.06	0.04	26,800
6	37.48	42.84	100.50	32.50	48.75	101.06	81.26	101.06	0.04	26,800
7	37.48	42.84	100.50	32.50	48.75	101.06	81.26	101.06	0.04	26,800
8	37.48	42.84	100.50	32.50	48.75	101.06	81.26	101.06	0.04	26,800
9	37.48	42.84	100.50	32.50	48.75	101.06	81.26	101.06	0.04	26,800
10	37.48	42.84	100.50	32.50	48.75	101.06	81.26	101.06	0.04	26,800
11	37.48	42.84	100.50	32.50	48.75	101.06	81.26	101.06	0.04	26,800
12	37.48	42.84	100.50	32.50	48.75	101.06	81.26	101.06	0.04	26,800

Table B. Measure Savings Including Distribution System Losses

Year	Measure Energy Savings (kWh)								Measure Demand Savings	Annual Water Savings
	Winter			Summer			Shoulder			
	On Peak	Mid-Peak	Off Peak	On Peak	Mid-Peak	Off Peak	Mid-Peak	Off Peak	On Peak (kW)	litres/yr
1	38.98	44.55	104.52	33.80	50.70	105.10	84.51	105.10	0.04	26,800
2	38.98	44.55	104.52	33.80	50.70	105.10	84.51	105.10	0.04	26,800
3	38.98	44.55	104.52	33.80	50.70	105.10	84.51	105.10	0.04	26,800
4	38.98	44.55	104.52	33.80	50.70	105.10	84.51	105.10	0.04	26,800
5	38.98	44.55	104.52	33.80	50.70	105.10	84.51	105.10	0.04	26,800
6	38.98	44.55	104.52	33.80	50.70	105.10	84.51	105.10	0.04	26,800
7	38.98	44.55	104.52	33.80	50.70	105.10	84.51	105.10	0.04	26,800
8	38.98	44.55	104.52	33.80	50.70	105.10	84.51	105.10	0.04	26,800
9	38.98	44.55	104.52	33.80	50.70	105.10	84.51	105.10	0.04	26,800
10	38.98	44.55	104.52	33.80	50.70	105.10	84.51	105.10	0.04	26,800
11	38.98	44.55	104.52	33.80	50.70	105.10	84.51	105.10	0.04	26,800
12	38.98	44.55	104.52	33.80	50.70	105.10	84.51	105.10	0.04	26,800

Table C. Avoided Electricity & Water Costs

Year	Ontario Seasonal Average Avoided Energy Cost (2005 CAD$/kWh)								Avoided Capacity Costs			Avoided Cost
	Winter			Summer			Shoulder		Generation	Transmission	Distribution	Water
	On Peak	Mid-Peak	Off Peak	On Peak	Mid-Peak	Off Peak	Mid-Peak	Off Peak	(2005 CAD$/kW-yr)			(2005 CAD$)
	602	688	1,614	522	783	1,623	1,305	1,623	N/A	N/A	N/A	N/A
1	$0.118	$0.082	$0.044	$0.110	$0.079	$0.046	$0.082	$0.041	$0.00	$0.00	$0.00	$0.7470
2	$0.119	$0.080	$0.043	$0.106	$0.076	$0.044	$0.078	$0.039	$0.00	$0.00	$0.00	$0.7470
3	$0.107	$0.081	$0.045	$0.103	$0.078	$0.047	$0.084	$0.042	$69.32	$5.22	$0.00	$0.7470
4	$0.101	$0.070	$0.044	$0.095	$0.072	$0.043	$0.078	$0.039	$75.71	$5.22	$6.50	$0.7470
5	$0.100	$0.068	$0.046	$0.095	$0.071	$0.043	$0.074	$0.038	$63.19	$5.22	$6.50	$0.7470
6	$0.095	$0.067	$0.045	$0.089	$0.070	$0.042	$0.073	$0.037	$73.65	$5.22	$6.50	$0.7470
7	$0.095	$0.066	$0.045	$0.095	$0.071	$0.043	$0.074	$0.040	$68.31	$5.22	$6.50	$0.7470
8	$0.103	$0.071	$0.049	$0.096	$0.075	$0.044	$0.076	$0.043	$50.55	$5.22	$6.50	$0.7470
9	$0.101	$0.074	$0.050	$0.102	$0.078	$0.045	$0.079	$0.044	$37.34	$5.22	$6.50	$0.7470
10	$0.100	$0.074	$0.054	$0.118	$0.083	$0.049	$0.080	$0.047	$18.10	$5.22	$6.50	$0.7470
11	$0.100	$0.074	$0.054	$0.116	$0.082	$0.049	$0.080	$0.047	$20.49	$5.22	$6.50	$0.7470
12	$0.101	$0.074	$0.054	$0.114	$0.081	$0.049	$0.079	$0.047	$22.26	$5.22	$6.50	$0.7470

Example 1: Technology Screening Analysis

Table A. Measure Savings

Year	Measure Energy Savings (kWh)								Measure Demand Savings
	Winter			Summer			Shoulder		
	On Peak	Mid-Peak	Off Peak	On Peak	Mid-Peak	Off Peak	Mid-Peak	Off Peak	On Peak (kW)
1	15.48	7.74	20.34	0	11.75	13.95	17.46	17.685	0
2	15.48	7.74	20.34	0	11.75	13.95	17.46	17.685	0
3	15.48	7.74	20.34	0	11.75	13.95	17.46	17.685	0
4	15.48	7.74	20.34	0	11.75	13.95	17.46	17.685	0

Table B. Measure Savings Including Distribution System Losses

Year	Measure Energy Savings (kWh)								Measure Demand Savings
	Winter			Summer			Shoulder		
	On Peak	Mid-Peak	Off Peak	On Peak	Mid-Peak	Off Peak	Mid-Peak	Off Peak	On Peak (kW)
1	16.0992	8.0496	21.1536	0	12.2148	14.508	18.1584	18.3924	0
2	16.0992	8.0496	21.1536	0	12.2148	14.508	18.1584	18.3924	0
3	16.0992	8.0496	21.1536	0	12.2148	14.508	18.1584	18.3924	0
4	16.0992	8.0496	21.1536	0	12.2148	14.508	18.1584	18.3924	0

Table C. Avoided Electricity Costs

Year	Ontario Seasonal Average Avoided Energy Cost (2005 CAD$/kWh)								Avoided Capacity		
	Winter			Summer			Shoulder		Generation	Transmission	Distribution
	On Peak	Mid-Peak	Off Peak	On Peak	Mid-Peak	Off Peak	Mid-Peak	Off Peak	(2005 CAD$/kW-yr)		
	602	688	1.614	522	783	1.623	1.305	1.623	N/A	N/A	N/A
1	$0.1178	$0.0819	$0.0443	$0.1102	$0.0794	$0.0463	$0.0821	$0.0413	$0.00	$0.00	$0.00
2	$0.1186	$0.0802	$0.0430	$0.1062	$0.0757	$0.0437	$0.0775	$0.0389	$0.00	$0.00	$0.00
3	$0.1072	$0.0806	$0.0454	$0.1027	$0.0776	$0.0466	$0.0839	$0.0417	$69.32	$5.22	$0.00
4	$0.1014	$0.0698	$0.0443	$0.0947	$0.0720	$0.0431	$0.0777	$0.0393	$75.71	$5.22	$6.50

Table D. Avoided Electricity Cost Savings

Year	Nominal Savings ($)								Nominal Savings ($)		
	Winter			Summer			Shoulder		Avoided Capacity Costs		
	On Peak	Mid-Peak	Off Peak	On Peak	Mid-Peak	Off Peak	Mid-Peak	Off Peak	Generation	Transmission	Distribution
1	$1.90	$0.66	$0.94	$0.00	$0.97	$0.67	$1.49	$0.76	$0.00	$0.00	$0.00
2	$1.91	$0.65	$0.91	$0.00	$0.92	$0.63	$1.41	$0.72	$0.00	$0.00	$0.00
3	$1.73	$0.65	$0.96	$0.00	$0.95	$0.68	$1.52	$0.77	$0.00	$0.00	$0.00
4	$1.63	$0.56	$0.94	$0.00	$0.88	$0.63	$1.41	$0.72	$0.00	$0.00	$0.00

Table E. Discounted Avoided Electricity Cost Savings

Year	Discount Rate Factor	Discounted Savings ($)								Discounted Savings ($)			Total Discounted Savings
		Winter			Summer			Shoulder		Avoided Capacity Costs			
		On Peak	Mid-Peak	Off Peak	On Peak	Mid-Peak	Off Peak	Mid-Peak	Off Peak	Generation	Transmission	Distribution	
1	1.0000	$1.8965	$0.6593	$0.9371	$0.0000	$0.9699	$0.6717	$1.4908	$0.7596	$0.0000	$0.0000	$0.0000	7.38
2	1.0750	$1.7762	$0.6005	$0.8461	$0.0000	$0.8601	$0.5898	$1.3091	$0.6655	$0.0000	$0.0000	$0.0000	6.65
3	1.1556	$1.4934	$0.5614	$0.8310	$0.0000	$0.8202	$0.5850	$1.3183	$0.6637	$0.0000	$0.0000	$0.0000	6.27
4	1.2423	$1.3141	$0.4523	$0.7543	$0.0000	$0.7079	$0.5033	$1.1357	$0.5818	$0.0000	$0.0000	$0.0000	5.45

Table F. Measure Costs and Benefits

Measure Benefits	Measure Costs
25.75	2.00

Example 2: Technology Screening Analysis

Table A. Measure Savings

Year	Measure Energy Savings (kWh)								Measure Demand Savings	Annual Water Savings
	Winter			Summer			Shoulder			
	On Peak	Mid-Peak	Off Peak	On Peak	Mid-Peak	Off Peak	Mid-Peak	Off Peak	On Peak (kW)	litres/yr
1	37.48	42.64	100.50	32.50	48.75	101.06	81.26	101.06	0.04	26,800
2	37.48	42.64	100.50	32.50	48.75	101.06	81.26	101.06	0.04	26,800
3	37.48	42.64	100.50	32.50	48.75	101.06	81.26	101.06	0.04	26,800
4	37.48	42.64	100.50	32.50	48.75	101.06	81.26	101.06	0.04	26,800
5	37.48	42.64	100.50	32.50	48.75	101.06	81.26	101.06	0.04	26,800
6	37.48	42.64	100.50	32.50	48.75	101.06	81.26	101.06	0.04	26,800
7	37.48	42.64	100.50	32.50	48.75	101.06	81.26	101.06	0.04	26,800
8	37.48	42.64	100.50	32.50	48.75	101.06	81.26	101.06	0.04	26,800
9	37.48	42.64	100.50	32.50	48.75	101.06	81.26	101.06	0.04	26,800
10	37.48	42.64	100.50	32.50	48.75	101.06	81.26	101.06	0.04	26,800
11	37.48	42.64	100.50	32.50	48.75	101.06	81.26	101.06	0.04	26,800
12	37.48	42.64	100.50	32.50	48.75	101.06	81.26	101.06	0.04	26,800

Table B. Measure Savings Including Distribution System Losses

Year	Measure Energy Savings (kWh)								Measure Demand Savings	Annual Water Savings
	Winter			Summer			Shoulder			
	On Peak	Mid-Peak	Off Peak	On Peak	Mid-Peak	Off Peak	Mid-Peak	Off Peak	On Peak (kW)	litres/yr
1	38.98	44.55	104.52	33.80	50.70	105.10	84.51	105.10	0.04	26,800
2	38.98	44.55	104.52	33.80	50.70	105.10	84.51	105.10	0.04	26,800
3	38.98	44.55	104.52	33.80	50.70	105.10	84.51	105.10	0.04	26,800
4	38.98	44.55	104.52	33.80	50.70	105.10	84.51	105.10	0.04	26,800
5	38.98	44.55	104.52	33.80	50.70	105.10	84.51	105.10	0.04	26,800
6	38.98	44.55	104.52	33.80	50.70	105.10	84.51	105.10	0.04	26,800
7	38.98	44.55	104.52	33.80	50.70	105.10	84.51	105.10	0.04	26,800
8	38.98	44.55	104.52	33.80	50.70	105.10	84.51	105.10	0.04	26,800
9	38.98	44.55	104.52	33.80	50.70	105.10	84.51	105.10	0.04	26,800
10	38.98	44.55	104.52	33.80	50.70	105.10	84.51	105.10	0.04	26,800
11	38.98	44.55	104.52	33.80	50.70	105.10	84.51	105.10	0.04	26,800
12	38.98	44.55	104.52	33.80	50.70	105.10	84.51	105.10	0.04	26,800

Table C. Avoided Electricity & Water Costs

Year	Ontario Seasonal Average Avoided Energy Cost (2005 CAD$/kWh)								Avoided Capacity Costs			Avoided Cost
	Winter			Summer			Shoulder		Generation	Transmission	Distribution	Water
	On Peak	Mid-Peak	Off Peak	On Peak	Mid-Peak	Off Peak	Mid-Peak	Off Peak	(2005 CAD$/kW-yr)			(2005 CAD$)
	602	688	1,614	522	783	1,623	1,305	1,623	N/A	N/A	N/A	N/A
1	$0.118	$0.082	$0.044	$0.110	$0.079	$0.046	$0.082	$0.041	$0.00	$0.00	$0.00	$0.7470
2	$0.119	$0.080	$0.043	$0.106	$0.076	$0.044	$0.078	$0.039	$0.00	$0.00	$0.00	$0.7470
3	$0.107	$0.081	$0.045	$0.103	$0.078	$0.047	$0.084	$0.042	$69.32	$5.22	$0.00	$0.7470
4	$0.101	$0.070	$0.044	$0.095	$0.072	$0.043	$0.078	$0.039	$75.71	$5.22	$6.50	$0.7470
5	$0.103	$0.068	$0.046	$0.095	$0.071	$0.043	$0.074	$0.038	$63.19	$5.22	$6.50	$0.7470
6	$0.095	$0.067	$0.045	$0.089	$0.070	$0.042	$0.073	$0.037	$73.65	$5.22	$6.50	$0.7470
7	$0.095	$0.066	$0.045	$0.095	$0.071	$0.043	$0.074	$0.040	$68.31	$5.22	$6.50	$0.7470
8	$0.101	$0.071	$0.049	$0.096	$0.075	$0.044	$0.076	$0.043	$50.55	$5.22	$6.50	$0.7470
9	$0.101	$0.074	$0.050	$0.102	$0.078	$0.045	$0.079	$0.044	$37.34	$5.22	$6.50	$0.7470
10	$0.100	$0.074	$0.054	$0.118	$0.083	$0.049	$0.080	$0.047	$18.10	$5.22	$6.50	$0.7470
11	$0.100	$0.074	$0.054	$0.116	$0.082	$0.049	$0.080	$0.047	$20.49	$5.22	$6.50	$0.7470
12	$0.101	$0.074	$0.054	$0.114	$0.081	$0.049	$0.079	$0.047	$22.26	$5.22	$6.50	$0.7470

Example 2: Technology Screening Analysis

Table D. Avoided Electricity & Water Cost Savings

Year	Savings ($)								Savings ($)			Savings ($)
	Winter			Summer			Shoulder		Avoided Capacity			
	On Peak	Mid-Peak	Off Peak	On Peak	Mid-Peak	Off Peak	Mid-Peak	Off Peak	Generation	Transmission	Distribution	Water
1	$4.59	$3.65	$4.63	$3.73	$4.03	$4.87	$6.94	$4.34	$0.00	$0.00	$0.00	$20.02
2	$4.62	$3.57	$4.49	$3.59	$3.84	$4.59	$6.55	$4.09	$0.00	$0.00	$0.00	$20.02
3	$4.18	$3.59	$4.75	$3.47	$3.93	$4.90	$7.09	$4.38	$2.70	$0.20	$0.00	$20.02
4	$3.95	$3.11	$4.63	$3.20	$3.65	$4.53	$6.57	$4.13	$2.95	$0.20	$0.25	$20.02
5	$3.91	$3.05	$4.82	$3.20	$3.61	$4.48	$6.24	$4.04	$2.46	$0.20	$0.25	$20.02
6	$3.70	$2.97	$4.75	$3.01	$3.55	$4.39	$6.14	$3.90	$2.87	$0.20	$0.25	$20.02
7	$3.68	$2.96	$4.68	$3.22	$3.61	$4.53	$6.29	$4.23	$2.66	$0.20	$0.25	$20.02
8	$4.00	$3.16	$5.14	$3.25	$3.80	$4.66	$6.41	$4.48	$1.97	$0.20	$0.25	$20.02
9	$3.93	$3.30	$5.26	$3.46	$3.93	$4.77	$6.69	$4.58	$1.46	$0.20	$0.25	$20.02
10	$3.88	$3.29	$5.69	$4.00	$4.23	$5.13	$6.79	$4.92	$0.71	$0.20	$0.25	$20.02
11	$3.91	$3.31	$5.64	$3.93	$4.18	$5.12	$6.73	$4.92	$0.80	$0.20	$0.25	$20.02
12	$3.94	$3.31	$5.60	$3.86	$4.13	$5.11	$6.68	$4.91	$0.87	$0.20	$0.25	$20.02

Table E. Discounted Avoided Electricity & Water Cost Savings

Year	Discount Rate Factor	Discounted Savings ($)								Discounted Savings ($)			Discounted Savings ($)	Total Savings
		Winter			Summer			Shoulder		Avoided Capacity				
		On Peak	Mid-Peak	Off Peak	On Peak	Mid-Peak	Off Peak	Mid-Peak	Off Peak	Generation	Transmission	Distribution	Water	
1	1.0000	$4.59	$3.65	$4.63	$3.73	$4.03	$4.87	$6.94	$4.34	$0.00	$0.00	$0.00	$20.02	**$56.79**
2	1.0750	$4.30	$3.32	$4.18	$3.34	$3.57	$4.27	$6.09	$3.80	$0.00	$0.00	$0.00	$18.62	**$51.51**
3	1.1556	$3.62	$3.11	$4.11	$3.00	$3.40	$4.24	$6.14	$3.79	$2.34	$0.18	$0.18	$17.32	**$51.42**
4	1.2423	$3.18	$2.50	$3.73	$2.58	$2.94	$3.65	$5.29	$3.32	$2.38	$0.16	$0.16	$16.11	**$46.00**
5	1.3355	$2.93	$2.28	$3.61	$2.39	$2.70	$3.35	$4.67	$3.02	$1.85	$0.15	$0.15	$14.99	**$42.10**
6	1.4356	$2.58	$2.07	$3.31	$2.10	$2.46	$3.06	$4.27	$2.72	$2.00	$0.14	$0.14	$13.94	**$38.80**
7	1.5433	$2.39	$1.92	$3.03	$2.09	$2.34	$2.94	$4.07	$2.74	$1.73	$0.13	$0.13	$12.97	**$36.47**
8	1.6590	$2.41	$1.90	$3.10	$1.96	$2.29	$2.81	$3.87	$2.70	$1.19	$0.12	$0.12	$12.07	**$34.53**
9	1.7835	$2.20	$1.85	$2.95	$1.94	$2.20	$2.68	$3.75	$2.57	$0.82	$0.11	$0.11	$11.23	**$32.41**
10	1.9172	$2.02	$1.72	$2.97	$2.09	$2.21	$2.68	$3.54	$2.57	$0.37	$0.11	$0.11	$10.44	**$30.80**
11	2.0610	$1.90	$1.60	$2.74	$1.91	$2.03	$2.48	$3.26	$2.39	$0.39	$0.10	$0.10	$9.71	**$28.61**
12	2.2156	$1.78	$1.50	$2.53	$1.74	$1.86	$2.31	$3.01	$2.22	$0.39	$0.09	$0.09	$9.04	**$26.55**

Table F. Measure Costs and Benefits

Year	Electricity Benefits	Water Benefits	Measure Costs
1	$36.77	$20.02	$7.00
2	$32.88	$18.62	
3	$34.10	$17.32	
4	$29.89	$16.11	
5	$27.11	$14.99	
6	$24.86	$13.94	
7	$23.50	$12.97	
8	$22.47	$12.07	
9	$21.18	$11.23	
10	$20.36	$10.44	
11	$18.90	$9.71	
12	$17.52	$9.04	
	$309.52	$166.47	
	$476.00		$7.00